TESTIMONY OF
PHILLIP D. WRIGHT
SENIOR VICE PRESIDENT, GAS PIPELINES
WILLIAMS

ON BEHALF OF THE
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

BEFORE THE
SUBCOMMITTEE ON ENERGY AND AIR QUALITY
COMMITTEE ON ENERGY AND COMMERCE
UNITED STATES HOUSE OF REPRESENTATIVES

REGARDING
NATURAL GAS AND HEATING OIL FOR AMERICAN HOMES

NOVEMBER 2, 2005

Mr. Chairman and Members of the Subcommittee:

Thank you for the opportunity to testify on this important topic. My name is Phil Wright, and I am Senior Vice President for Gas Pipelines at Williams. Williams is the second-largest transporter of natural gas in the United States, transporting about 12 percent of the natural gas consumed. We operate three interstate pipelines which provide natural gas to major markets on both the east and west coasts including Atlanta, the Carolinas, Philadelphia, New York, Seattle, Portland and Florida. These systems total about 15,000 miles of pipe, transporting natural gas from the Gulf of Mexico, Canada, the Rocky Mountains and other production areas.

I am here today on behalf of the Interstate Natural Gas Association of America (INGAA). INGAA is a trade organization that represents the interstate natural gas transmission pipeline companies operating in the U.S., as well as comparable companies in Canada and Mexico. Its members transport over 95 percent of the nation's natural gas through a network of 180,000 miles of pipelines.

Natural Gas Pipeline Industry

Before discussing the winter outlook for natural gas supplies, I first want to make a few points about the structure of the natural gas industry. The natural gas industry has never been as vertically integrated as the oil and electric power industries. Put differently, it is the exception and not the rule for a single company to be significantly involved in all segments of the industry. These segments can generally be broken down into the following categories: production, gathering and processing (also known as midstream services), interstate pipelines, marketing, and local distribution. Some of these segments are subject to economic (i.e., rate) regulation at the federal or state level, while others are not subject to any rate regulation.

The Federal Energy Regulatory Commission (FERC) regulates the rates, terms and conditions of service for the interstate pipeline segment. As part of the natural gas industry restructuring that occurred during the 1980s and early 1990s, the interstate pipeline industry gave up its merchant role as the provider of bundled wholesale natural gas services. Under the current industry structure, interstate pipelines transport and store natural gas, but do not produce, purchase or sell the commodity. An interstate pipeline is analogous to a trucking company that provides both transportation and warehousing services for goods, but that does not take title to the goods. The maximum rate an interstate pipeline may charge for transportation and storage is set by FERC on a pipeline-by-pipeline basis, based upon the costs incurred by a specific pipeline to provide such services.

Pipeline transportation and storage is the smallest part of the cost of natural gas delivered to residential and commercial customers – typically about 10 percent of the total retail cost of natural gas. (See Appendix 1) Pipelines earn their revenues by charging the regulated rates for transportation and storage set by FERC; since pipelines have no role in purchasing and reselling natural gas, they do not benefit from higher commodity prices.

The shippers (i.e., customers) on interstate pipelines – who may be local distribution companies (LDCs), municipal gas companies, electric generators or industrial companies – are responsible for purchasing natural gas and arranging pipeline transportation and storage. Each shipper is responsible for its own portfolio of natural gas supply, transportation and storage. A customer's natural gas supply portfolio may include long-term and short-term contracts and spot market purchases, as well as financial instruments to manage price risk. In the case of pipeline transportation, a shipper can choose to purchase firm transportation that ensures year-round availability (including on the coldest days of the year) or a shipper can choose to purchase various types of non-firm transportation that may be interrupted during periods of greatest natural gas consumption. Non-firm capacity generally is sold at rates lower than firm service, but the shipper accepts the risk that this capacity will be unavailable during a peak period when firm transportation customers are fully utilizing their entitlement to pipeline capacity. Pipeline companies build additional facilities to add pipeline capacity if shippers are willing to sign long-term firm contracts for such capacity. Still, due to the time required to comply with new construction certification and permitting requirements and to construct the facility, there often is a multi-year lag between the inception of a pipeline project and when natural gas can flow through the newly-completed capacity.

While the business model for the natural gas industry is not vertically integrated, there are significant operational interdependencies between the industry's various segments. This is especially true regarding off-shore production in the Gulf of Mexico, an important consideration in evaluating gas supply availability for the upcoming winter. Generally speaking, the chain of delivery is as follows: Natural gas is first produced at off-shore platform or wellhead facilities; it is then gathered and transported through smaller diameter gathering pipelines for redelivery to FERC-regulated transmission pipelines for transportation to onshore processing plants. There, the natural gas is processed to remove hydrocarbon liquids, such as propane and butane. Those processed liquids must be transported, via dedicated pipeline, barge or truck, to markets for those products, such as refineries and petrochemical facilities. Once the liquids are removed, the natural gas is fit for consumption and is redelivered into the interstate pipeline network where it is transported to end-use customers. These systems all must work together for natural gas to flow onshore, and from there to the millions of customers downstream. If any link in this delivery chain is disrupted, the remaining links in the chain will be affected in some way.

Hurricanes Katrina and Rita have highlighted these interdependencies. In cases where multiple links in the supply chain have been damaged, we cannot repair only a single link and expect natural gas supplies to return to pre-hurricane levels. All of the links must be working in order to achieve that result.

Effect of the Hurricanes

Mr. Chairman, two major hurricanes striking back-to-back at the heart of our nation's energy system have caused an unprecedented disruption in our Gulf-based natural gas infrastructure. The federal waters in the Gulf of Mexico account for about 10 billion cubic feet per day (bcfd) of natural gas production, which is about 20 percent of total U.S. production. As of early this week, about 55 percent of this daily production, or about 5.5 bcfd, remained "shut-in" due to the storms. To place this number in perspective, the United States typically consumes on average 61 bcfd nationwide. Given the tight supply/demand balance that the nation already was facing before the hurricanes, this loss of supply – even if only temporary – is cause for concern as we begin the winter heating season.

The media, and indeed most Americans, have focused most intently on how the twin hurricanes have affected the price and supply of gasoline. Gulf Coast oil production and refineries are a critical part of the nation's infrastructure for obtaining supplies of gasoline, jet fuel and fuel oil. Nonetheless, the United States imports almost 60 percent of its petroleum supplies from overseas. This means that a short-term increase in imports can mitigate some portion of the impact of the hurricanes on petroleum supplies. When it comes to natural gas, however, the United States still produces 85 percent of the total supplies needed to meet domestic demand. Most of the remaining supply comes from Canada. The United States' ability to import natural gas from outside North America is far more limited than with petroleum, given the small number (5) of operational liquefied natural gas (LNG) import terminals in the U.S. Therefore, even as the country remains focused on gasoline prices, the more profound and protracted impact of the hurricanes will be on natural gas prices and supplies.

I want to assure the Committee that we are doing all we can to repair or bypass the hurricane damage to natural gas infrastructure in the Gulf region. The dedication of our employees, in the face of losing their homes and possessions and having their families uprooted, has been phenomenal. Across the industry, people are showing up to work long hours even as they have no place to go home to. Supporting our employees with temporary housing within the region so they can continue to repair and operate critical energy facilities is crucial to speeding the pace at which natural gas supplies in the Gulf can be brought back online.

Winter Supply Outlook

Let me now turn to our outlook for the winter heating season. There can be no doubt that, compared to last year, there will be less natural gas delivered from the Gulf of Mexico region this winter. The damage is too widespread, and the amount of repair work too great, for everything to be repaired in time for the winter heating season. The fundamentals of supply and demand in the North American natural gas market already were tight before hurricanes Katrina and Rita. Consequently, any loss of supply – even a relatively small one – can have a disproportionate impact on natural gas prices over the winter. This tight supply and demand balance places extra emphasis on natural gas storage.

While it is largely invisible to the public, the United States has a significant amount of natural gas storage scattered throughout the country. These storage facilities, typically located in depleted oil and gas fields, usually are filled during the warmer months when there is excess natural gas supply and pipeline capacity to move it. Storage fills are generally completed by November 1st, which is the beginning of the winter heating season. During the coldest winter days, which typically are the days of peak natural gas demand, storage withdrawals meet more than 50 percent of the daily natural gas load in some market areas.

Prior to the hurricanes, storage fills were proceeding at total volumes above the five-year average. The hurricanes slowed storage fills somewhat, but volumes still remain ahead of the five-year average. On this first week of the winter heating season, the storage fill stands at about 3.1 trillion cubic feet – a robust number given the damage in the Gulf. The significant damage to industry and to homes and businesses in the Gulf region greatly reduced natural gas demand September and October. This loss of load partially offset the diminished natural gas production from the Gulf and freed up gas supply that could be diverted to storage in preparation for the upcoming winter.

Still, it cannot be emphasized enough that storage supplements– but does not replace – natural gas flowing through the interstate pipeline network. Many of the interstate pipelines serving the Midwest, Northeast and Southeast draw their primary supplies from the Gulf region. There are physical limits on how much natural gas can be drawn from storage on a daily basis and it is assumed that storage will be withdrawn at its full capacity on a peak day. Therefore, if supply constraints limit the volumes of natural gas available for transportation, peak day conditions could create deliverability challenges in some markets. While peak day conditions could occur at any point during the winter, the risk of deliverability challenges will become greater as storage becomes increasingly depleted during the late winter months. This could create significant operational challenges for pipelines in late winter, particularly if cold weather, limited supply availability, and low storage cause customers to attempt to take more gas from a given pipeline than has been delivered to the pipeline on their behalf.

I should also mention the importance of returning damaged natural gas processing facilities to service. As mentioned previously, natural gas processing plants remove the heavier hydrocarbons entrained within produced natural gas. These natural gas liquids include propane, ethane and butane. Once removed, there is a separate market for these liquids, principally in the petrochemical industry. Just as with oil refineries in the Gulf region, however, a number of natural gas processing plants were damaged by the hurricanes. Several of these facilities may be out of operation during most, if not all, of the winter.

This presents another operational challenge for pipelines. A certain amount of unprocessed natural gas can be accepted into the natural gas pipeline network. If the quantity of heavier hydrocarbons in the gas stream becomes too high, however, these substances can "drop out" of the natural gas stream as liquids and collect in pipelines and end-use equipment. This is a particular concern during the winter heating season when the lower ambient temperatures cause the temperature of the flowing gas to drop, increasing the volume of heavy hydrocarbons that will return to the liquid state. This phenomenon can cause safety and operational problems as slugs of liquids work their way through sensitive equipment. Therefore, as off-shore production facilities come back on line, it is also important to bring corresponding processing capacity back on line as well. Otherwise, pipelines may be compelled to strictly enforce their tariffs to limit the volumes of unprocessed natural gas that can be accepted during the winter heating season in order to preserve the operational integrity of the transmission and distribution pipelines and protect end-users, even if it means reducing the volumes of natural gas that can be delivered during peak demand periods.

Winter Supply Analysis

Because of our concern about these potential winter supply scenarios, INGAA retained an economic consultant, Energy and Environmental Analysis Inc. (EEA), to analyze the adequacy of natural gas supplies (including gas storage) for the upcoming winter. **This study includes a detailed analysis of the effects on natural gas deliverability from Hurricanes Katrina and Rita.** The primary objective of the study is to analyze the likelihood that, due to the effects of the hurricanes, individual natural gas markets (i.e., consuming regions) within North America could experience difficulties that would lead to supply curtailment for certain customers (primarily industrial users and electric generators).

INGAA believes that the EEA study is noteworthy in several respects. First, the study is premised on EEA's Gas Market Data and Forecasting System, a model of the North American natural gas market that examines supply and demand balances at individual points within the natural gas infrastructure. This permits an examination of individual natural gas markets that takes into account the particular features of the infrastructure and gas flows. This takes the analysis to a level beyond conclusions based solely on nationwide aggregate supply and demand. EEA's model has been used for three widely referenced natural gas market studies in recent years: the 2003 National Petroleum Council study; the 2004 and 2005 INGAA Foundation studies on natural gas infrastructure needs; and the 2005 American Gas Foundation study.

Second, the EEA study has benefited from broad participation by representatives from both government and industry. This has included natural gas industry representatives from individual pipeline companies, natural gas processing companies and natural gas producers. Trade association participants have included INGAA, the American Gas Association (AGA), the Natural Gas Supply Association (NGSA), the Independent Petroleum Association of America (IPAA) and the American Petroleum Institute (API). Federal agency participants have included representatives from the Department of Energy (DOE), the Energy Information Administration (EIA), the Minerals Management Service (MMS) and FERC. The input assumptions for the study represent the collective views of all these participants.

One key point in the results is worth mentioning first. The EEA analysis concludes that, assuming curtailment plans work as expected, **residential and commercial customers served by local distribution companies that hold firm transportation and gas supply**

entitlements will continue receiving natural gas service, sufficient to meet their requirements throughout the winter, even during periods of peak demand. These customers will receive natural gas this winter, albeit at higher prices. The study, however, does not, and cannot, account for individual cases where a particular LDC, municipal utility or gas marketer may experience difficulties because it has not adequately secured transportation or supply for the winter. Still, should they occur, such situations would be isolated.

The EEA study examines three different hurricane recovery and supply scenarios this winter – a base case, a best case, and a worst case. These supply scenarios are then analyzed within the context of winter weather probabilities to determine the likelihood that particular consuming markets will experience stressed conditions as the weather turns colder. EEA assumes that an average of between 2.5 bcfd (best case) and 3.5 bcfd (worst case) of Gulf supplies will be missing from the market due to hurricane damage. This loss of supply is netted against supplies from other sources to determine an overall effect on gas supply. This will result in higher-than-normal gas commodity prices, even if the winter is relatively mild.

EEA's analysis makes an important point that should not be lost on policymakers. That is, even before the hurricanes, natural gas supply and demand were very tightly balanced and there already was some potential for supply challenges this winter. The hurricanes simply have increased the probability that both industrial and power generation customers in certain markets may experience supply disruptions.

The severity of winter weather will be a critical factor in determining how natural gas markets will balance. Industrial demand destruction, as a result of high commodity prices, will help maintain this balance to a point. Still, if the weather is colder-than-normal, the probability of gas supply curtailments becomes greater.

What do we mean by "gas curtailments?" For purposes of the EEA study, the term is defined as follows: a curtailment situation occurs when the analysis indicates that gas supply into a market will be insufficient to meet all demand even after all economic alternatives have been exhausted. As gas commodity prices move higher due to tight supply and high demand, many customers will scale back their consumption and the market will re-balance. In some limited circumstances, however, economic forces alone might not be enough to balance the market. In these cases, certain customers must be removed from service for short periods in order for the market to balance. Generally speaking, these curtailments affect industrial and power generation customers.

These curtailments would be localized. The likelihood of such curtailments would increase if winter weather is five percent or greater colder than normal. Historically, this type of weather occurs in one out of every seven winters.

Curtailments, if any, are likely to be concentrated east of the Mississippi River, with the likelihood being greatest in the Northeast. This is because the United States east-of-the-Mississippi is far more dependent on Gulf Coast natural gas supplies than is the rest of the country, and because the Northeast (compared to other regions) has fewer natural gas supply alternatives. Therefore, New York and New England have the highest probability of gas curtailments in all the scenarios, although other states might also be affected should the winter be colder than normal. (See Appendix 2)

Delayed recovery of Gulf Coast supplies significantly increases the likelihood of curtailments as well, particularly on the East Coast. This is illustrated by the worst case scenario in the EEA analysis and highlights the need to facilitate Gulf Coast energy infrastructure recovery as quickly as possible.

One final point about gas curtailments. If and when necessary, gas curtailments will not be a large percent of total winter natural gas load. Still, because such mandated interruptions would be concentrated within a particularly cold week or two, a significant part of the total industrial and power load within an affected market could be curtailed for that span of time.

Short-Term Recommendations

What can be done? As previously mentioned, the short-term imperative is repairing the infrastructure as quickly as possible. That means expediting permitting and approvals for repair work. It also means the various levels of government should consider the value of granting individual companies some forbearance from legal restrictions that might frustrate their ability to coordinate assessment and repair activities. The twin hurricanes have resulted in extraordinary damage, and extraordinary measures are needed to get systems repaired on a timely basis.

Also in the short-term, both the energy industry and the government must educate consumers in advance so they are prepared for higher bills and have the ability to implement strategies for conserving energy. This is important, because unlike the gasoline price that is posted at the local gas station, the consumer sees the price of natural gas after the fact when he or she receives a bill for the previous month's consumption. Many of you are already familiar with some of these measures, including weatherization of homes, regular inspections of furnaces and changing of filters, installing programmable thermostats and setting thermostats a couple of degrees cooler than normal. Funding the Low Income Heating Energy Assistance (LIHEAP) program is also critical in helping needy families cope with rising heating costs.

The EEA analysis also points to the need to review local distribution company curtailment programs. The last time that natural gas supply curtailments were a major issue – during the 1970s – FERC regulated interstate pipelines played a major role in instituting curtailments. Due to the restructuring of the natural gas industry, however, interstate pipelines no longer are gas merchants and pipeline tariffs no longer address supply curtailment based on end-use priority. Such curtailments now are largely the purview of state public utility commissions, and state regulators should be reviewing their plans and preparing to implement them if necessary. This would include coordinating any plans with local electric generators who would be some of the most likely customers to be curtailed.

Wholesale natural gas customers should also be consulting with their suppliers about firm supply arrangements. This includes portfolios of storage, flowing supply, pipeline transportation and peak shaving. In the absence of such supply verification, wholesale customers – and in some cases, the retail customers served by such wholesale customers – may be in for some rude winter surprises.

Long-Term Recommendations

In the long-term, Mr. Chairman, we agree with many on this Committee that more must be done to diversify our supplies of natural gas. Hurricanes Katrina and Rita have clearly demonstrated the nation's high degree of reliance on the Gulf region to meet its energy needs. Other regions within the United States can, and should, be a part of the nation's energy supply and infrastructure development strategy. Yes, many groups have complained about the environmental risks associated with expanding offshore energy to include waters outside the western Gulf of Mexico. Still, after three significant hurricanes in two years, it is time to concede that apprehensions about the environmental consequences of offshore energy development are greatly overstated. The fact that we have not had significant environmental damage from off-shore production platforms after Ivan, Katrina and Rita must stand for something. Our national energy policy should not be premised on hypothetical problems or on assumptions based on incidents from 40 years ago.

In addition, the United States must build new liquefied natural gas import terminals to keep pace with our demand for this fuel. Most of the new terminals that recently have been approved by FERC have are proposed to be constructed in the Gulf of Mexico region. While there are good reasons why this region is attractive, such as access to an extensive pipeline network, it stands out that the Gulf has been attractive for energy infrastructure development because it offers the "path of least resistance" in terms of "Not in My Back Yard" type opposition. Perhaps the hurricanes, and the effects this winter on natural gas prices and the larger economy, will convince other regions in the United States of the importance of having a geographically diverse mix of these facilities.

For both supply and infrastructure development, a re-focus on long-term contracting is needed. When natural gas commodity prices were low due to excess supply, state public utility commissions discouraged their regulated gas LDCs from entering into long-term contracts for natural gas supply and transportation. Long-term contracts, however, are critical to financing and developing new supplies and infrastructure (pipelines, storage and LNG terminals). Long-term contracts also are an insurance policy against high prices and volatility. A joint task force representing the National Association of Regulatory Utility Commissioners (NARUC) and the Interstate Oil and Gas Compact Commission (IOGCC) recently produced a set of recommendations intended to encourage a return longer-term contracting in the natural gas industry; INGAA urges state commissions to review the NARUC/IOGCC report and to support more balanced supply and transportation contract portfolios for regulated utilities.

Finally, it is worth examining the factors that have precluded electric generators from installing dual-fuel capability when building a gas-fired power plant. Over the last decade, dual-fueled facilities – facilities that can operate on both natural gas and fuel oil – have been discouraged by emissions limits and by the difficulty in siting oil storage facilities on site. Also, the rules in some electric power markets provide such generators no assurances that the additional capital cost of such facilities can be recovered in the price received for electricity. These factors have compelled developers to build power plants totally dependent on natural gas. These same market rules have discouraged electric generators from contracting for firm natural gas transportation and storage service. Should natural gas supplies remain tight this winter, these facilities will face the choice of either paying huge fuel charges, or not running at all.

Conclusion

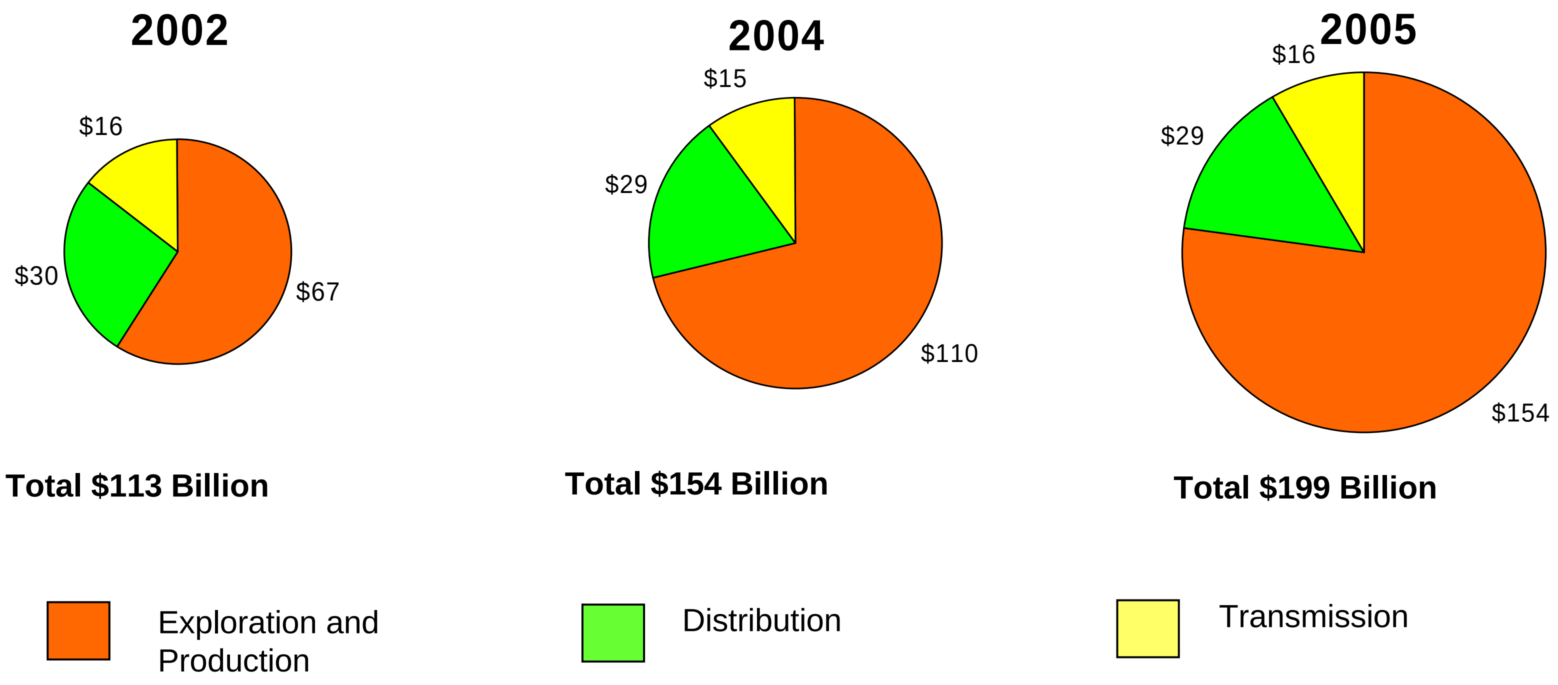
Some have questioned whether the energy industry is investing enough capital into the North American market to develop supply and mitigate prices in the long-term. Mr. Chairman, while I can speak only for the interstate pipeline sector of the industry, I want to assure you that we are committed to this market long-term and are putting our capital into this market as a result. An INGAA Foundation report released last year suggested that the industry would need to invest approximately $61 billion between now and 2020 in order to keep pace with demand. This is for natural gas infrastructure – pipelines, storage and LNG terminals – in the United States and Canada. As an industry we are moving forward with that investment, and I am including a list of the proposed projects announced in 2005 as an example. (See Appendix 3)

Before I conclude, I want to suggest some public policy responses that should <u>not</u> be undertaken. During a crisis, it is easy to overreact in ways that are ultimately counterproductive. The first suggestion I would like to leave you with is this: please do not try to regulate commodity prices. This country actually did regulate natural gas prices for many years, resulting in artificial supply shortages and a misallocation of resources. Similarly, the government should not attempt to pick winners and losers in allocating scarce supplies among end-users. Some have debated limiting the use of natural gas for electric generation. This too was tried in the past and failed miserably. While it can be painful in the short run, the market really does the best job of efficiently allocating scare resources and sending the right price signals that will solve supply problems.

Mr. Chairman and Members of the Subcommittee, I thank you once again for the opportunity to testify, and I will be happy to answer your questions.

Appendix 1

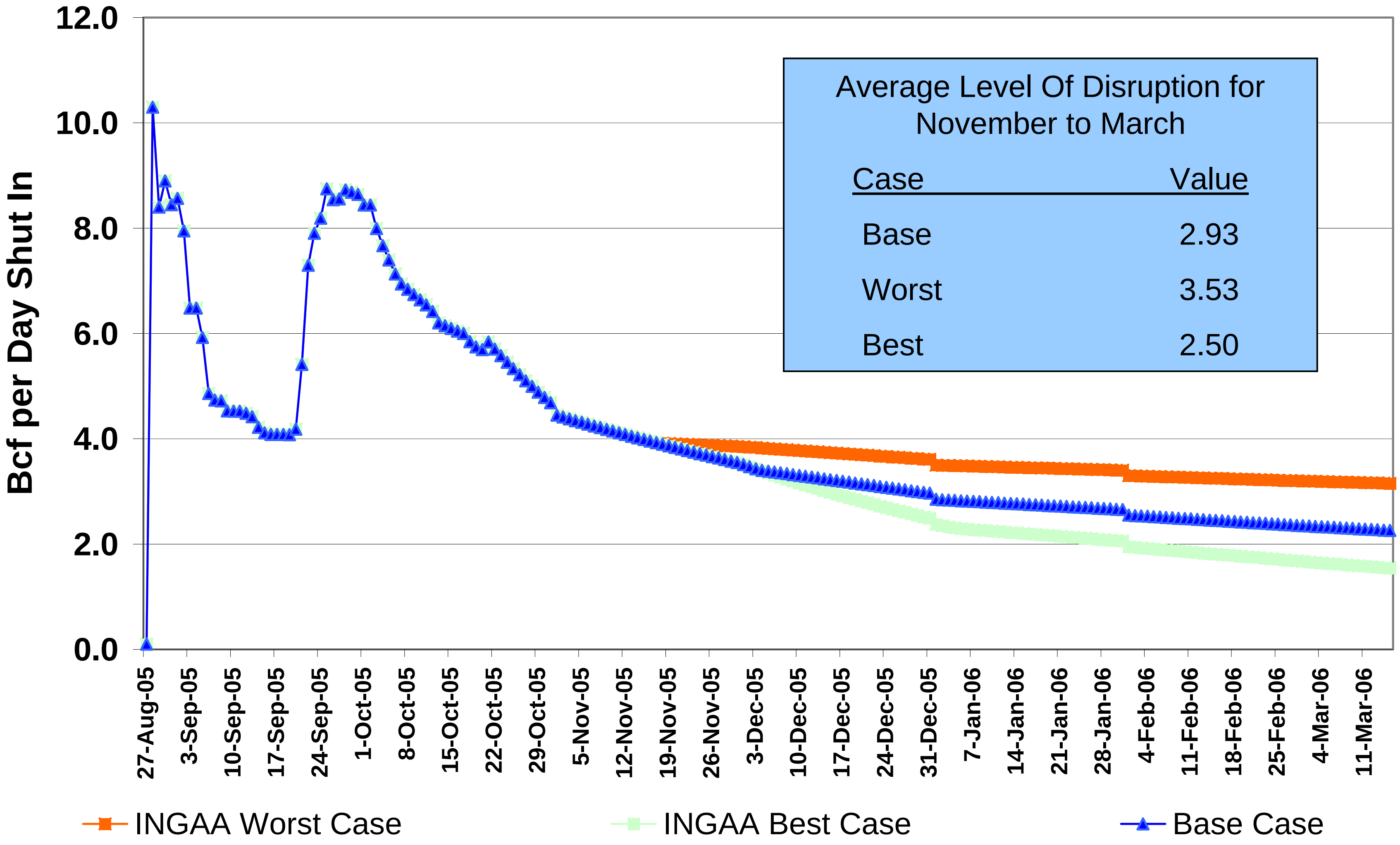
Estimated Industry Revenues (Billions 2004$)



Estimated using EEA's Burner-tip price processor and EEA's October 2005 Compass Base Case

Appendix 2

Comparison of Gulf Coast Recovery Scenarios

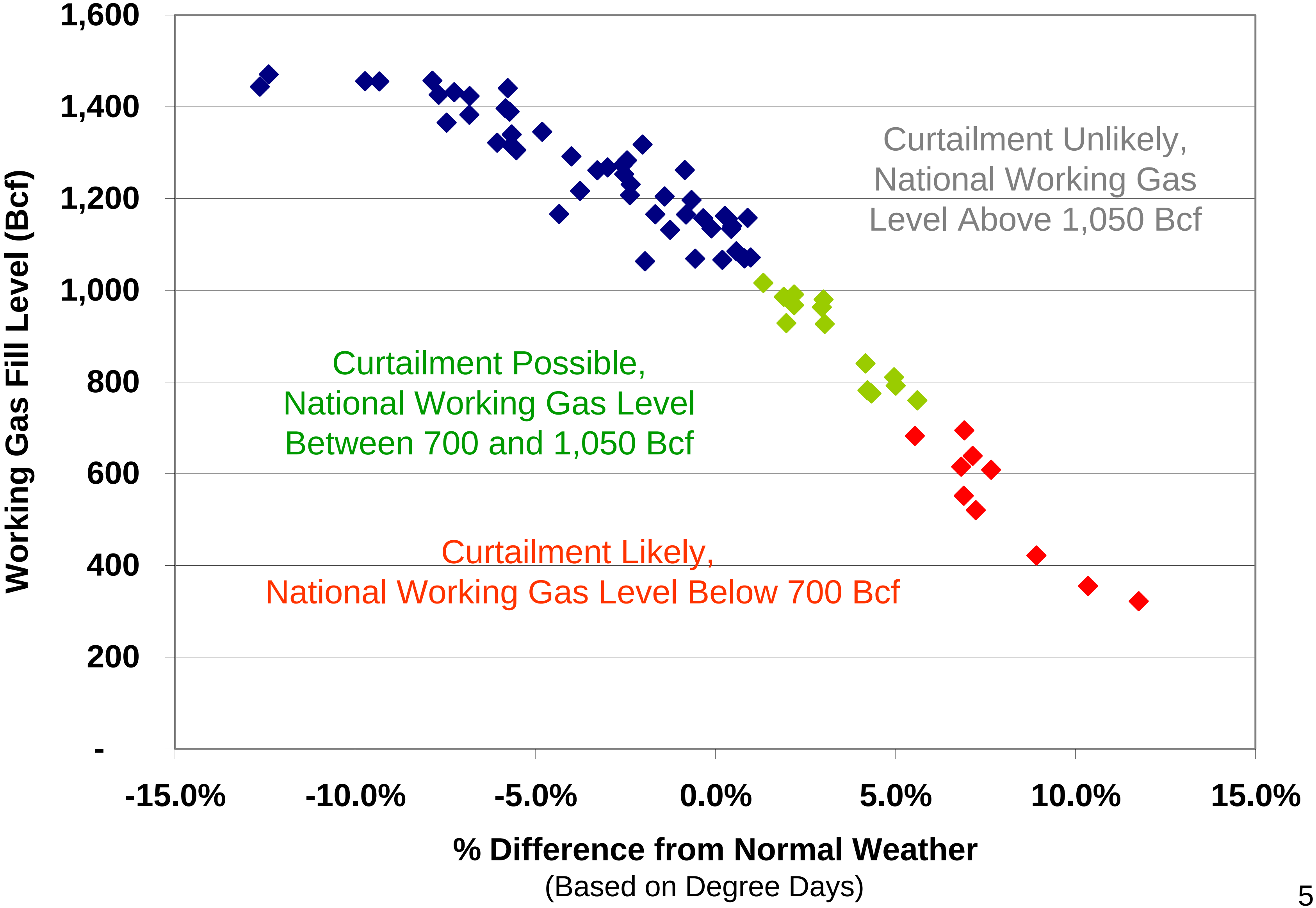


Average Level Of Disruption for November to March

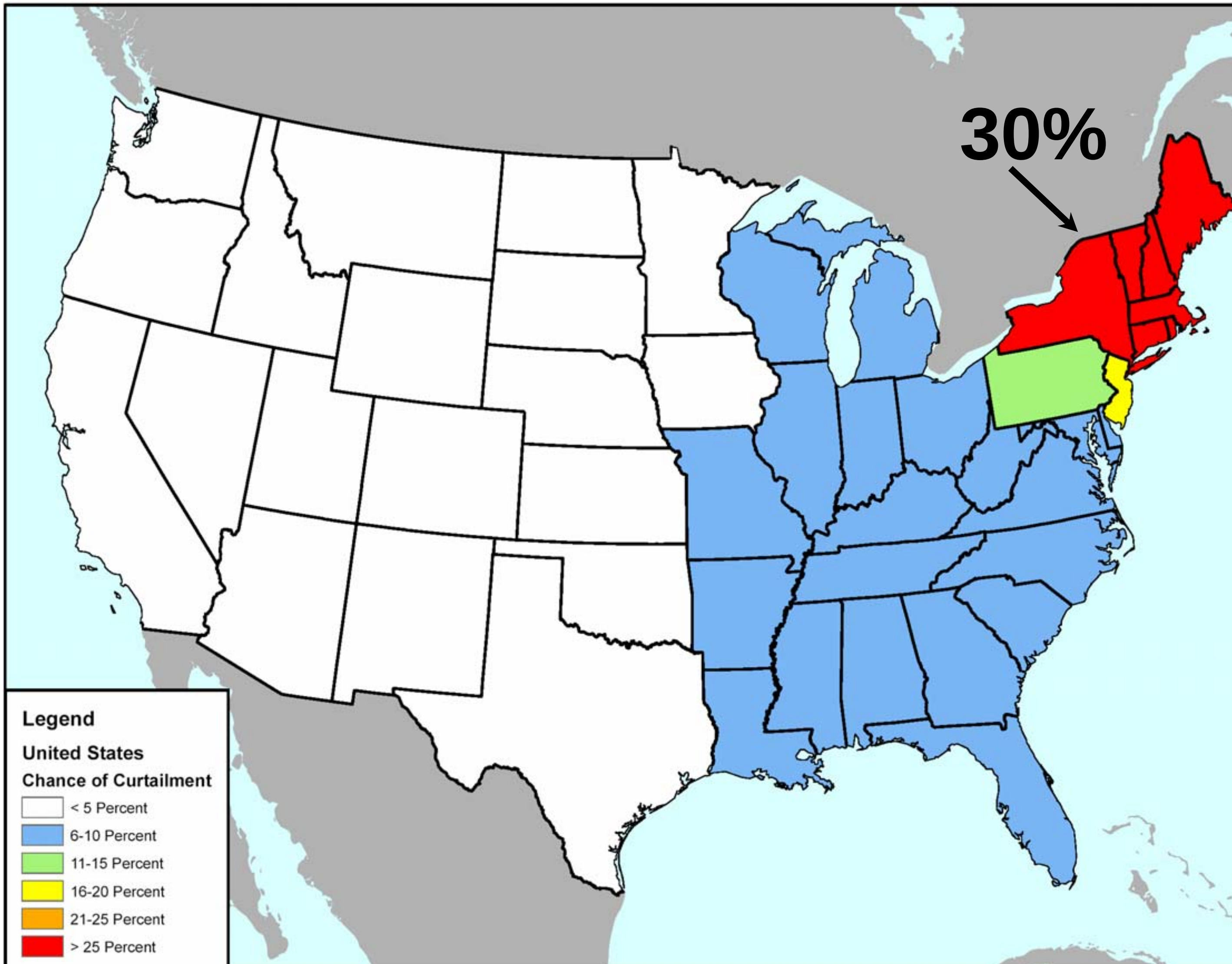
Case	Value
Base	2.93
Worst	3.53
Best	2.50

Note: Includes both offshore and onshore production.

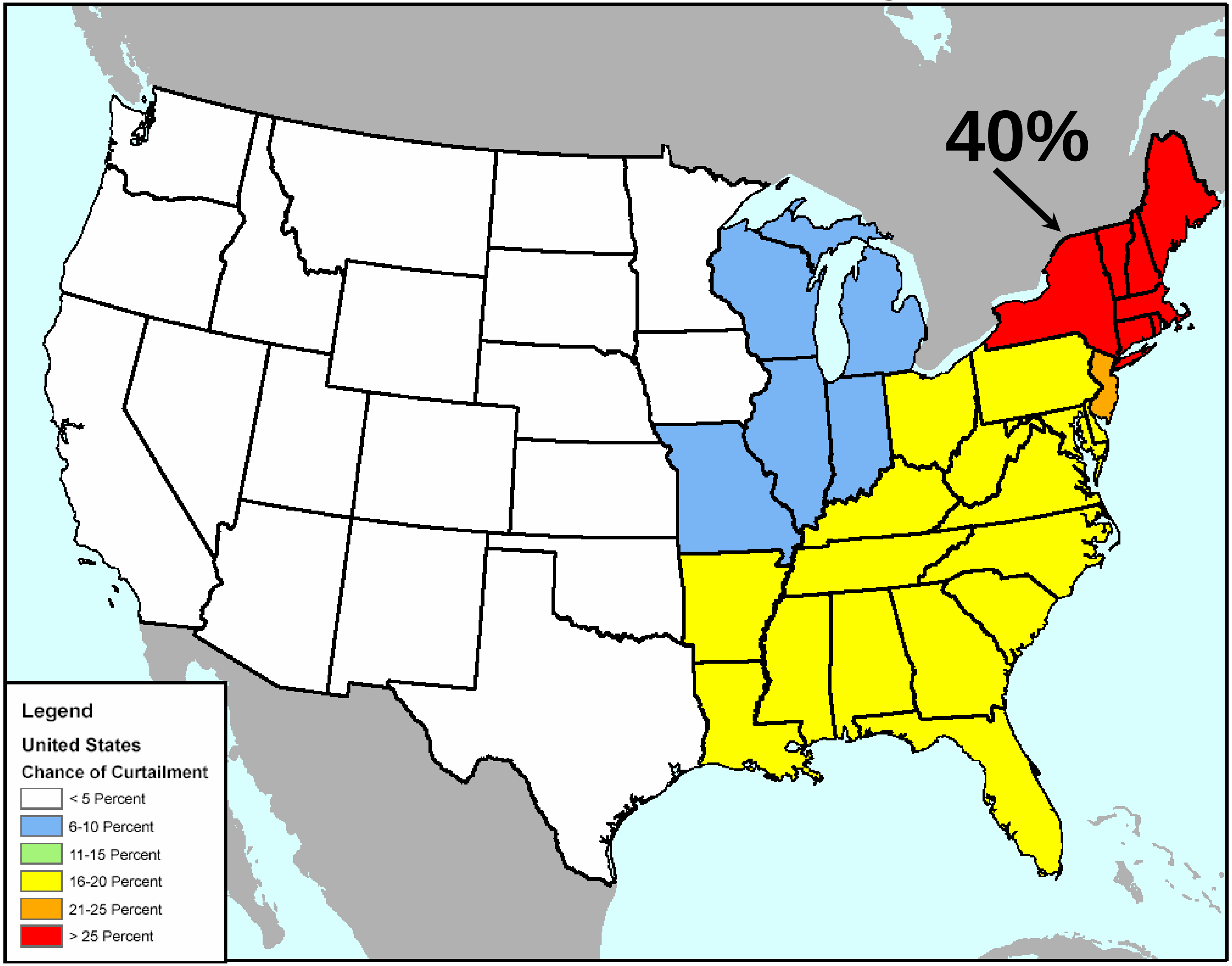
INGAA Base Case Recovery Scenario
U.S. End of March 2006 Working Gas Levels Versus Weather



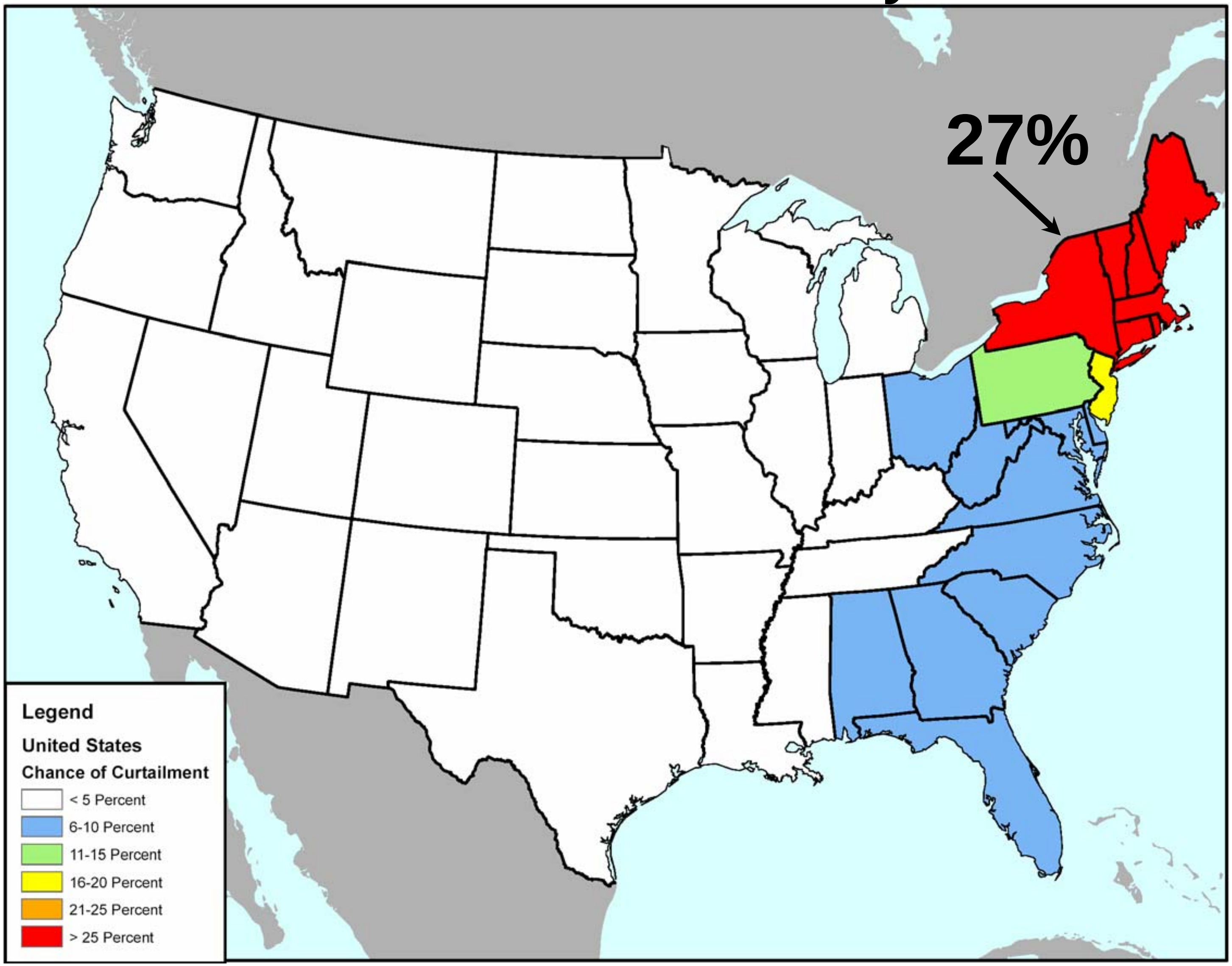
INGAA Base Case Recovery Scenario Curtailment Probability



INGAA Worst Case Recovery Scenario Curtailment Probability

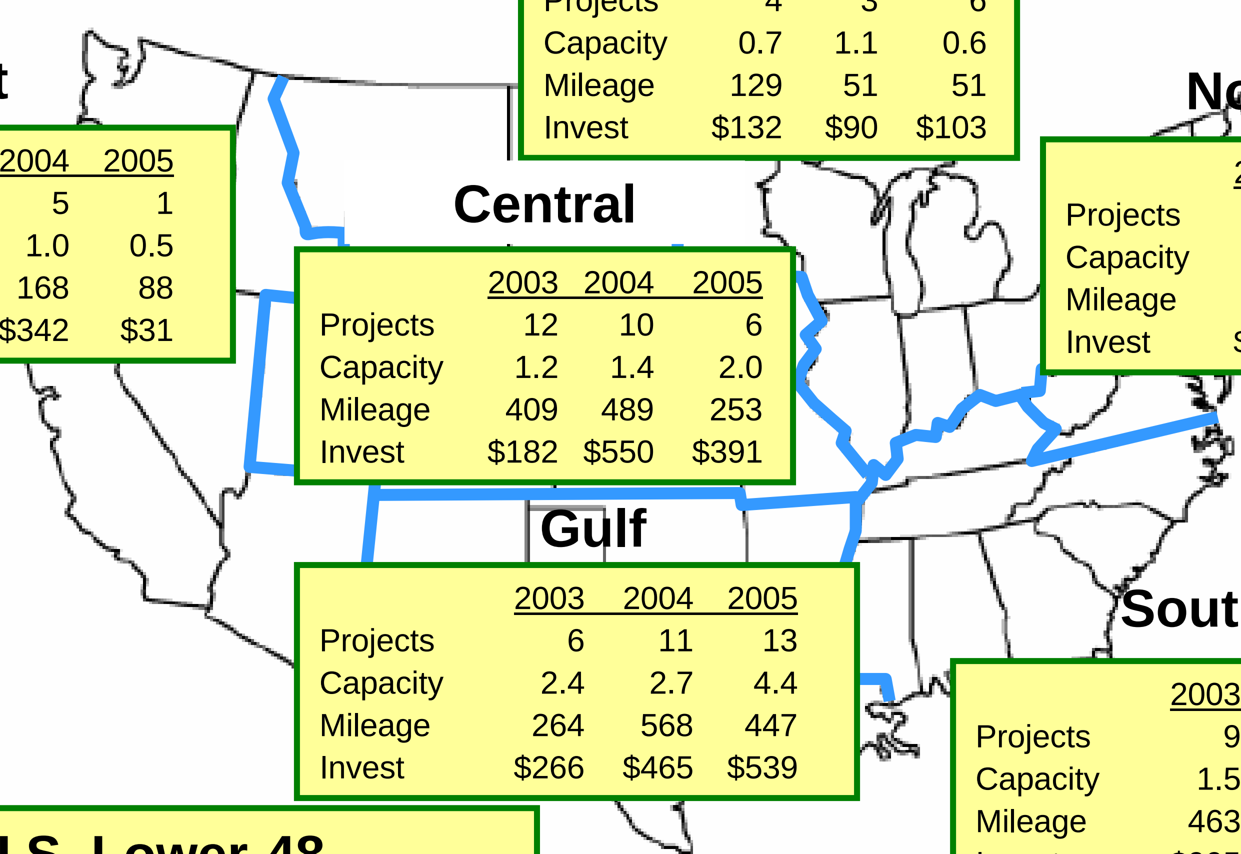


INGAA Best Case Recovery Scenario Curtailment Probability



Appendix 3

Recent Pipeline Capacity Investments



Midwest

	2003	2004	2005
Projects	4	3	6
Capacity	0.7	1.1	0.6
Mileage	129	51	51
Invest	$132	$90	$103

West

	2003	2004	2005
Projects	6	5	1
Capacity	2.4	1.0	0.5
Mileage	885	168	88
Invest	$1,693	$342	$31

Northeast

	2003	2004	2005
Projects	8	8	5
Capacity	1.3	0.8	0.6
Mileage	82	116	22
Invest	$346	$543	$74

Central

	2003	2004	2005
Projects	12	10	6
Capacity	1.2	1.4	2.0
Mileage	409	489	253
Invest	$182	$550	$391

Gulf

	2003	2004	2005
Projects	6	11	13
Capacity	2.4	2.7	4.4
Mileage	264	568	447
Invest	$266	$465	$539

Southeast

	2003	2004	2005
Projects	9	3	2
Capacity	1.5	0.5	0.4
Mileage	463	58	113
Invest	$905	$136	$240

U.S. Lower-48

	2003	2004	2005	Total	
Projects	49	41	33	123	
Capacity	10.4	7.7	8.5	26.6	Bcfd
Mileage	2,243	1,459	974	4,676	Miles
Invest	$3,565	$2,128	$1,378	$7,071	Million's $

Source: E.I.A., Office of Oil and Gas
2005 Estimated.

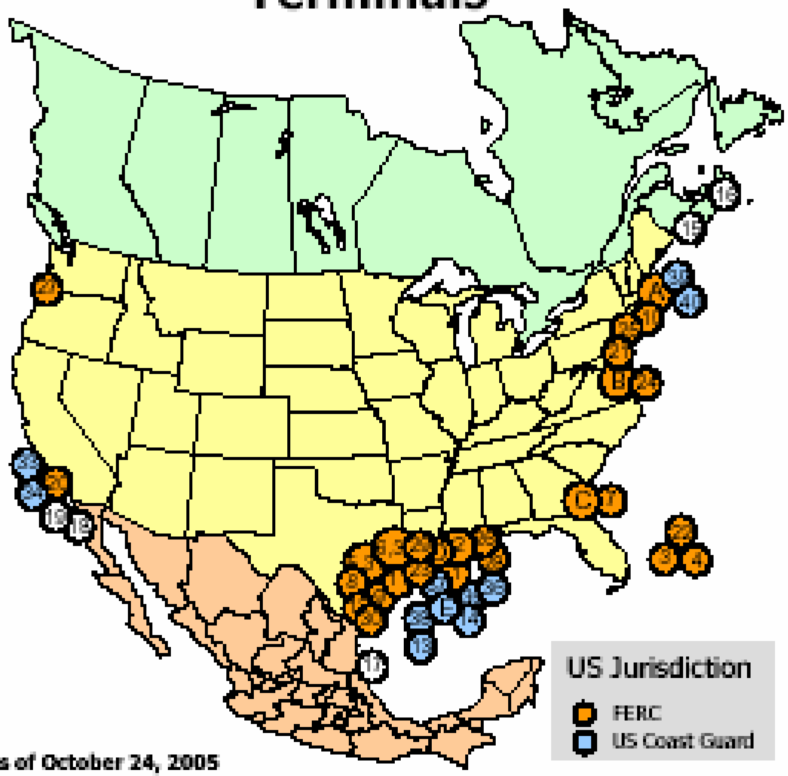
Major Proposed Pipeline and LNG Capacity Investments

- **LNG Terminals**
  - 17.6 Bcfd Certificated (16 Projects)
  - 26.7 Bcfd Pending (21 Projects)
  - 6.2 Bcfd Announced (10 Projects)
- **Pipeline Project Totals**
  - 5.3 Bcfd Certificated (11 Projects)
  - 6.8 Bcfd Pending (10 Projects)
  - 13.7 Bcfd Announced (17 Projects)

- **Arctic Pipeline Projects**
  - 4.0 Bcfd - Announced
- **Northeast Pipeline Projects**
  - 0.5 Bcfd Certificated
  - 0.9 Bcfd Pending
  - 1.4 Bcfd Announced
- **Central Pipeline Projects**
  - 0.2 Bcfd Certificated
  - 4.0 Bcfd Announced
- **Gulf Pipeline Projects**
  - 1.8 Bcfd Announced
- **Midwest Pipeline Projects**
  - 0.4 Bcfd Certificated
  - 1.0 Bcfd Announced
- **West Pipeline Projects**
  - 2.6Bcfd Certificated
  - 1.0 Bcfd Pending
  - 1.5 Bcfd Announced
- **Southeast Pipeline Projects**
  - 1.7 Bcfd Certificated
  - 1.7 Bcfd Pending

FERC

Existing and Proposed North American LNG Terminals



As of October 24, 2005

* *US pipeline approved; LNG terminal pending in Bahamas*

CONSTRUCTED

A. Everett, MA : 1.035 Bcfd (Tractebel - DOMAC)
B. Cove Point, MD : 1.0 Bcfd (Dominion - Cove Point LNG)
C. Elba Island, GA : 0.68 Bcfd (El Paso - Southern LNG)
D. Lake Charles, LA : 1.0 Bcfd (Southern Union - Trunkline LNG)
E. Gulf of Mexico: 0.5 Bcfd, (Gulf Gateway Energy Bridge - Excelerate Energy)

APPROVED BY FERC

1. Lake Charles, LA: 0.6 Bcfd (Southern Union - Trunkline LNG)
2. Hackberry, LA : 1.5 Bcfd, (Sempra Energy)
3. Bahamas : 0.84 Bcfd, (AES Ocean Express)*
4. Bahamas : 0.83 Bcfd, (Calypso Tractebel)*
5. Freeport, TX : 1.5 Bcfd, (Cheniere/Freeport LNG Dev.)
6. Sabine, LA : 2.6 Bcfd (Cheniere LNG)
7. Elba Island, GA: 0.54 Bcfd (El Paso - Southern LNG)
8. Corpus Christi, TX: 2.6 Bcfd, (Cheniere LNG)
9. Corpus Christi, TX : 1.0 Bcfd (Vista Del Sol - ExxonMobil)
10. Fall River, MA : 0.8 Bcfd, (Weaver's Cove Energy/Hess LNG)
11. Sabine, TX : 1.0 Bcfd (Golden Pass - ExxonMobil)
12. Corpus Christi, TX: 1.0 Bcfd (Ingleside Energy - Occidental Energy Ventures)

APPROVED BY MARAD/COAST GUARD

13. Port Pelican: 1.6 Bcfd, (Chevron Texaco)
14. Louisiana Offshore : 1.0 Bcfd (Gulf Landing - Shell)

CANADIAN APPROVED TERMINALS

15. St. John, NB : 1.0 Bcfd, (Canaport - Irving Oil)
16. Point Tupper, NS 1.0 Bcf/d (Bear Head LNG - Anadarko)

MEXICAN APPROVED TERMINALS

17. Altamira, Tamulipas : 0.7 Bcfd, (Shell/Total/Mitsui)
18. Baja California, MX : 1.0 Bcfd, (Sempra)
19. Baja California - Offshore : 1.4 Bcfd, (Chevron Texaco)

PROPOSED TO FERC

20. Long Beach, CA : 0.7 Bcfd, (Mitsubishi/ConocoPhillips - Sound Energy Solutions
21. Logan Township, NJ : 1.2 Bcfd (Crown Landing LNG - BP)
22. Bahamas : 0.5 Bcfd, (Seafarer - El Paso/FPL)
23. Port Arthur, TX: 1.5 Bcfd (Sempra)
24. Cove Point, MD : 0.8 Bcfd (Dominion)
25. LI Sound, NY: 1.0 Bcfd (Broadwater Energy - TransCanada/Shell)
26. Pascagoula, MS: 1.0 Bcfd (Gulf LNG Energy LLC)
27. Bradwood, OR: 1.0 Bcfd (Northern Star LNG - Northern Star Natural Gas LLC)
28. Pascagoula, MS: 1.3 Bcfd (Casotte Landing - ChevronTexaco)
29. Cameron, LA: 3.3 Bcfd (Creole Trail LNG - Cheniere LNG)
30. Port Lavaca, TX: 1.0 Bcfd (Calhoun LNG - Gulf Coast LNG Partners)
31. Freeport, TX: 2.5 Bcfd (Cheniere/Freeport LNG Dev. - Expansion)
32. Sabine, LA: 1.4 Bcfd (Cheniere LNG - Expansion)

PROPOSED TO MARAD/COAST GUARD

33. California Offshore: 1.5 Bcfd (Cabrillo Port - BHP Billiton)
34. So. California Offshore : 0.5 Bcfd, (Crystal Energy)
35. Louisiana Offshore : 1.0 Bcfd (Main Pass McMoRan Exp.)
36. Gulf of Mexico: 1.0 Bcfd (Compass Port - ConocoPhillips)
37. Gulf of Mexico: 2.8 Bcfd (Pearl Crossing - ExxonMobil)
38. Gulf of Mexico: 1.5 Bcfd (Beacon Port Clean Energy Terminal - ConocoPhillips)
39. Offshore Boston, MA: 0.4 Bcfd (Neptune LNG - Tractebel)
40. Offshore Boston, MA: 0.8 Bcfd (Northeast Gateway - Excelerate Energy)

Office of Energy Projects